

BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

In the Matter of:)

)

Application of Duke Energy Carolinas, LLC)

Docket No. 2018-319-E

for Adjustments in Electric Rate Schedules)

and Tariffs)

DIRECT TESTIMONY OF

JONATHAN WALLACH

ON BEHALF OF

SOUTH CAROLINA STATE CONFERENCE OF THE NATIONAL ASSOCIATION FOR

THE ADVANCEMENT OF COLORED PEOPLE, SOUTH CAROLINA COASTAL

CONSERVATION LEAGUE, AND UPSTATE FOREVER

Resource Insight, Inc.

FEBRUARY 26, 2019

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1 **I. Introduction and Summary**

2 **Q: Please state your name, occupation, and business address.**

3 A: My name is Jonathan F. Wallach. I am Vice President of Resource Insight,
4 Inc., 5 Water Street, Arlington, Massachusetts.

5 **Q: Please summarize your professional experience.**

6 A: I have worked as a consultant to the electric power industry since 1981.
7 From 1981 to 1986, I was a Research Associate at Energy Systems
8 Research Group. In 1987 and 1988, I was an independent consultant. From
9 1989 to 1990, I was a Senior Analyst at Komanoff Energy Associates. I
10 have been in my current position at Resource Insight since 1990.

11 Over the past four decades, I have advised and testified on behalf of
12 clients on a wide range of economic, planning, and policy issues relating to
13 the regulation of electric utilities, including: electric-utility restructuring;
14 wholesale-power market design and operations; transmission pricing and
15 policy; market-price forecasting; market valuation of generating assets and
16 purchase contracts; power-procurement strategies; risk assessment and
17 mitigation; integrated resource planning; mergers and acquisitions; cost
18 allocation and rate design; and energy-efficiency program design and
19 planning.

20 My resume is attached as Exhibit JFW-1.

21 **Q: Have you testified previously in utility proceedings?**

22 A: Yes. I have sponsored expert testimony in more than 90 state, provincial,
23 and federal proceedings in the U.S. and Canada. I include a detailed list of
24 my previous testimony in Exhibit JFW-1.

1 **Q: On whose behalf are you testifying?**

2 A: I am testifying on behalf of the South Carolina State Conference of the
3 National Association for the Advancement of Colored People (“SC
4 NAACP”), the South Carolina Coastal Conservation League (“CCL”), and
5 Upstate Forever.

6 **Q: Are you sponsoring any exhibits?**

7 A: Yes. I am sponsoring the following exhibits:

- 8 • Exhibit JFW-1: Resume of Jonathan Wallach, Resource Insight, Inc.
- 9 • Exhibit JFW-2: Citations to Marginal-Price Elasticity Studies

10 **Q: What is the purpose of your testimony?**

11 A: On November 8, 2018, Duke Energy Carolinas, LLC (“DEC” or “the
12 Company”) filed with the Public Service Commission of South Carolina
13 (“Commission”) an application and supporting testimony for approval of
14 increased electric rates and charges. My testimony explains why the
15 Commission should reject the Company’s proposal to increase the monthly
16 Basic Facilities Charge (“BFC”) for residential customers. I respond to the
17 testimony of Company witness Janice Hager regarding the Company’s cost
18 of service study (“COSS”), which served as the basis for its proposal to
19 increase the BFC, and the testimony of Company witness Michael J. Pirro
20 regarding DEC’s proposed increase in the BFC.

21 **Q: Please summarize your findings and recommendations.**

22 A: The Company has not justified its proposal to more than triple the
23 residential BFC. The Company proposes to increase the residential BFC in
24 order to recover all costs classified as “customer-related” in its cost of
25 service study (“COSS”). However, contrary to long-standing Commission
26 precedent, DEC has classified a portion of the cost of its distribution grid as

1 customer-related in the COSS based on a “minimum-system” analysis.¹
2 This inherently flawed analysis erroneously classifies some distribution-
3 grid costs—a portion of the cost of poles, wires, conduits, and
4 transformers—as customer-related, even though they are in fact driven by
5 usage and therefore properly classified as “demand-related.” The
6 Company’s COSS thereby overstates the amount of customer-related costs
7 appropriately recovered through the residential BFC.

8 Accordingly, the Commission should reject the Company’s reliance on
9 a minimum-system analysis to classify distribution-grid costs as customer-
10 related in the COSS. Instead, as has been the practice for the past three
11 decades and consistent with this Commission’s directive, DEC should
12 classify all such distribution-grid costs as demand-related. Only the costs
13 incurred by DEC to connect customers to the distribution grid – i.e., the cost
14 of meters, service drops (the line connecting a residence to the grid) and
15 meter-reading, billing, and other customer-service expenses – should be
16 classified as customer-related.

17 The Company’s proposal to recover distribution-grid costs through the
18 residential BFC also runs contrary to established principles for designing
19 cost-based rates since it would inappropriately shift recovery of costs driven
20 by usage from the volumetric energy rate to the fixed BFC. As explained in
21 more detail below, the Company’s proposal to recover usage-driven costs
22 through the residential BFC would:

¹ In a 1991 order granting a rate increase to DEC’s predecessor, Duke Power Company, the Commission found that “the Minimum System concept should be eliminated from Duke’s cost of service study”. Order No. 91-1022, Docket No. 91-216-E, 7 (Nov. 18, 1991).

- 1 • Lead to subsidization of high-usage residential customers' costs by
2 low-usage customers, and thereby inequitably increase bills for the
3 Company's low-usage residential customers.
- 4 • Dampen price signals to consumers for controlling their bills through
5 conservation, energy efficiency, or distributed renewable generation.

6 Consequently, the Commission should reject the Company's proposal
7 to increase the BFC for residential customers. Instead, consistent with
8 enduring cost-causation and rate-design principles and in order to protect
9 low-income customers from undue harm, I recommend that the BFC for the
10 residential rate classes be increased from current levels by the same
11 percentage as the revenue increase (if any) ultimately authorized by the
12 Commission in this proceeding for those classes.

13 **Q: How is the rest of your testimony organized?**

14 A: In Section II, I describe the Company's proposal for increasing the
15 residential BFC. In Section III, I discuss how the Company's COSS
16 misclassifies demand-related distribution-grid costs as customer-related. In
17 Section IV, I explain how DEC's proposal to increase the residential BFC
18 violates long-standing principles of cost-based rate design. In Section V, I
19 discuss how DEC's proposal would give rise to unreasonable cost
20 subsidization within the residential class. In Section VI, I discuss how the
21 Company's proposal would dampen energy price signals. Finally, I provide
22 my conclusions and recommendations in Section VII.
23

1 **II. DEC's Proposal to Increase the Residential BFC**

2 **Q: What is the Basic Facilities Charge?**

3 A: The BFC is a fixed fee charged to each customer on their monthly bill
4 regardless of the customer's energy usage during that month.

5 **Q: What is the Company's proposal with respect to the BFC for residential**
6 **customers?**

7 A: For residential customers taking standard service under Schedules RS, RE,
8 ES, or ESA, DEC proposes to more than triple the BFC from \$8.29 to
9 \$28.00 per customer per month. For residential customers taking time-of-
10 use service under Schedule RT, DEC proposes to nearly triple the BFC from
11 \$9.93 to \$27.08 per customer per month.²

12 **Q: What is the basis for the Company's proposal to increase the residential**
13 **BFC?**

14 A: According to Company witness Pirro, DEC proposes to increase the
15 residential BFC in order to recover the residential classes' share of the costs
16 classified as customer-related in the Company's COSS.³

17 **Q: Does the Company's COSS provide a reasonable basis for increasing**
18 **the residential BFC?**

² Pirro Direct Exhibit No. 6, attached to *Direct Testimony of Michael J. Pirro for Duke Energy Carolinas, LLC*, Docket No. 2018-319-E (November 8, 2018) [hereinafter "Pirro Direct"]. Standard residential service is provided under Schedule RS. Schedule RE is applicable to residential customers who use electricity for all major end-uses. Schedule ES is applicable to residential customers whose homes meet Energy Star standards. Schedule ESA is applicable to residential customers who use electricity for all major end-uses and whose homes meet Energy Star standards.

³ Pirro Direct, 15.

1 A: No. As discussed below in Section III, the Company's COSS erroneously
2 classifies some distribution costs as customer-related and therefore
3 overstates the amount of customer-related costs that are eligible for
4 recovery through the residential BFC.

5 **Q: What is the purpose of the Company's COSS?**

6 A: The purpose of the COSS is to allocate the Company's total revenue
7 requirement to the various rate classes in a manner that reasonably reflects
8 each class's contribution to that revenue requirement.

9 **Q: Please describe how the total revenue requirement is allocated to rate**
10 **classes in the Company's COSS.**

11 A: In order to allocate the total revenue requirement to rate classes, the COSS
12 first separates that total into production, transmission, distribution, and
13 customer cost functions. Costs in each function are then classified as
14 energy-, demand-, or customer-related based on whether costs are
15 considered to be "caused" by energy sales, peak demand, or the number of
16 customers, respectively. Finally, costs classified as either energy-, demand-,
17 or customer-related are allocated to customer classes in proportion to each
18 class's contribution to total-system energy sales, peak demand, or number
19 of customers, respectively.

20 **Q: Please describe how costs are classified in the Company's COSS.**

21 A: The Company classifies the costs of meters, service drops, and customer
22 services as customer-related in the COSS. As I discuss below in Section III,
23 these are the only categories of costs that are properly classified as
24 customer-related.

25 In addition, the Company relies on a "minimum-system" analysis to
26 classify some distribution-grid costs – a portion of pole, conductor, conduit,

1 and line-transformer costs – as customer-related. As discussed in Section
2 III, the minimum-system classification methodology is fundamentally
3 flawed and incorrectly classifies distribution-grid costs as customer-related.

4 The remaining portion of pole, conductor, conduit, and line-
5 transformer costs not classified as customer-related are instead classified as
6 demand-related in the COSS, along with all production and transmission
7 plant and fixed operations and maintenance (“O&M”) costs. Finally, fuel
8 and variable O&M costs are classified as energy-related.

9 **Q: Please describe how the Company uses the minimum-system analysis to**
10 **classify some pole, conductor, conduit, and line-transformer costs as**
11 **customer-related.**

12 A: The Company’s minimum-system analysis attempts to estimate the cost to
13 install the same amount of poles, conductors, conduit, and line transformers
14 as are currently on the distribution system, assuming that each piece of
15 distribution equipment is sized to meet minimal load.⁴ In other words, the
16 Company’s minimum-system analysis attempts to estimate the cost to
17 replicate the configuration of the existing distribution grid using
18 “minimum-size” equipment.

19 The Company’s COSS classifies the cost of this hypothetical
20 minimum-size distribution grid as customer-related. The difference between
21 the test-year cost of the distribution grid and the estimated cost of the
22 hypothetical minimum-size distribution grid is classified as demand-related
23 in the Company’s COSS.

⁴ *Direct Testimony of Janice Hager for Duke Energy Carolinas, LLC*, Docket No. 2018-319-E, 14 (November 8, 2018) [Hereinafter “Hager Direct”].

1 **Q: Is there another method that utilities typically use to classify**
2 **distribution costs?**

3 A: Yes. Under the Basic Customer method, only the costs of meters, service
4 drops, and customer services are classified as customer-related and all other
5 distribution costs are classified as demand-related.

6 **Q: Does DEC propose to recover all of the costs classified as customer-**
7 **related in its COSS through the residential BFC?**

8 A: Yes. Based on the minimum-system approach, the Company's COSS
9 estimates a customer-related cost of \$28.00 per residential customer taking
10 standard service and \$27.08 per residential customer taking time-of-use
11 service. The Company proposes to collect these amounts through the BFC
12 for standard-service and time-of-use residential customers, respectively.⁵

13 **III. DEC's COSS Misclassifies Distribution Costs**

14 **Q: Is the Company's proposal to classify distribution costs based on a**
15 **minimum-system analysis a break from past practice?**

16 A: Yes. As far as I am aware, DEC has been relying on the Basic Customer
17 method to classify distribution costs as demand-related ever since the
18 Commission ordered the Company to stop relying on the minimum-system
19 classification method in 1991.

20 **Q: Has DEC explained why it decided in this proceeding to not comply**
21 **with the Commission's 1991 directive and instead to start relying on the**
22 **minimum-system classification method?**

⁵ Pirro Direct Exhibit No. 6.

1 A: No. Instead, Company witness Hager opines that continued reliance on the
 2 Basic Customer method would yield cost classifications that are “counter to
 3 cost causation principles.”⁶

4 **Q: Do you agree with Ms. Hager’s contention that the Basic Customer**
 5 **method produces cost classifications that are inconsistent with cost-**
 6 **causation principles?**

7 A: No. To the contrary, it is the minimum-system classification approach
 8 adopted by DEC in this proceeding which classifies distribution costs
 9 inconsistently with cost-causation principles.

10 **Q: Why are minimum-system classifications inconsistent with cost-**
 11 **causation?**

12 A: The minimum-system method suffers from a number of fundamental flaws
 13 which lead to classifications that are contrary to cost-causation principles.

14 For one, the minimum-system approach implausibly assumes that a
 15 utility would incur costs to build a distribution grid to serve customers that
 16 have no load. As noted in a study by the Regulatory Assistance Project:

17 ... the threshold assumption is that there is some portion of the system
 18 whose costs are unrelated to demand (or to energy for that matter).
 19 From one perspective, this notion has a certain intuitive appeal —
 20 these are the lowest costs that must be incurred before any or some
 21 minimal amount of power can be delivered — but from another
 22 viewpoint it seems absurd, since in the absence of any demand no such
 23 system would be built at all.⁷

⁶ Hager Direct, 15.

⁷ Frederick Weston, *Charging for Distribution Utility Services: Issues in Rate Design*, Regulatory Assistance Project, 31 (December, 2000), available at <https://www.raponline.org/wp-content/uploads/2016/05/rap-weston-chargingfordistributionutilityservices-2000-12.pdf>.

1 For another, the minimum-system approach erroneously assumes that
 2 the minimum system would consist of the same number of units (e.g.,
 3 number of poles, feet of conductors) as the actual system. In reality, load
 4 levels help determine the number of units, as well as their size. Minimum-
 5 system analyses ignore the effect of loads on the number of units installed,
 6 or the type of equipment installed, classifying some costs as customer-
 7 related even though they are really driven by demand.

8 Finally, the minimum-system method fails to account for the fact that
 9 even the minimum-size equipment currently installed on the system has
 10 some amount of load-carrying capability. Consequently, some portion of the
 11 cost for this minimum-size equipment should be classified as demand-
 12 related. However, under the minimum-system method, that demand-related
 13 portion of the cost of the minimum-sized equipment is instead misclassified
 14 as customer-related.⁸

15 **Q: What is the magnitude of misclassified cost under the Company's**
 16 **minimum-system classification?**

17 A: I estimate that about \$71 million of the distribution-grid costs allocated to
 18 the residential rate classes in the COSS have been misclassified as
 19 customer-related under the Company's minimum-system method.

20 **Q: How did you derive your estimate of misclassified cost?**

21 A: In response to a data request, DEC provided the unit cost results from its
 22 COSS and from a cost of service study that classifies distribution costs
 23 using the Basic Customer method.⁹ These results show that the Company's

⁸ George J. Sterzinger, "The Customer Charge and Problems of Double Allocation of Costs", *Public Utilities Fortnightly*, (July 2, 1981).

⁹ DEC response to Vote Solar Data Request No. 1-20.

1 COSS classifies about \$165 million of residential revenue requirements as
2 customer-related, while the revised cost of service study based on the Basic
3 Customer method classifies about \$94 million of residential revenue
4 requirements as customer-related. The \$71 million difference between these
5 two results represents demand-related distribution-grid costs that have been
6 misclassified as customer-related under the Company's minimum-system
7 classification method.

8 **Q: How would these misclassified costs be recovered under the Company's**
9 **proposal for the residential BFC?**

10 A: As noted in Section II, DEC proposes to recover through the residential
11 BFC all costs that the Company's COSS classified as customer-related (and
12 allocated to the residential classes). Thus, the proposed residential BFC
13 would recover not just costs that are truly customer-related but also those
14 distribution-grid costs that are erroneously classified as customer-related in
15 the Company's COSS.

16 **Q: What do you recommend with regard to the Company's proposal to**
17 **rely on the minimum-system method to classify distribution costs in its**
18 **cost of service study?**

19 A: The Commission should reject the Company's use of the minimum-system
20 method to classify distribution-grid costs. Instead, DEC should be directed
21 to continue the long-standing practice adopted by the Commission in 1991
22 of classifying distribution costs in cost of service studies using the Basic
23 Customer method.

IV. DEC's Proposed Increase to the Residential BFC Violates Principles of Cost-Based Rate Design

Q: How did DEC use the results of its COSS in the design of proposed rates for the residential rate classes?

A: As discussed above in Section II, the Company proposes to set the residential BFC at the rate that would recover the residential classes' share of costs classified as customer-related with the minimum-system method in the COSS. The Company further proposes to set the energy charge for each residential rate class at the rate that would recover the difference between each class's share of requested total revenues and the revenues collected from that class through the proposed BFC.

Q: What are the relevant considerations in designing cost-based rates for residential customers?

A: The primary challenge in rate design is to reflect the costs that customers impose on the system, both to share costs fairly and to encourage economically efficient usage of utility resources. Accordingly, fixed customer charges should reflect the fact that each customer contributes equally to certain types of costs regardless of that customer's energy usage. Volumetric energy rates, on the other hand, recognize that customers of different sizes and load profiles contribute to other types of costs at different levels. If usage-driven costs are inappropriately collected through fixed customer charges, then customers will have reduced incentives to control

1 their bills through conservation or investments in energy efficiency or
2 distributed renewable generation.¹⁰

3 **Q: Given these considerations, what categories of costs are appropriately**
4 **recovered through the volumetric energy rate?**

5 A: In order to provide cost-based price signals, volumetric energy rates should
6 be set at levels that recover those categories of costs that are driven by
7 customer usage over the long run. This includes plant, fuel, and O&M costs
8 for the production, transmission, and distribution functions, along with
9 certain customer-service costs that tend to vary with usage, such as
10 uncollectible costs.¹¹

11 In other words, volumetric energy rates should reflect long-run
12 marginal costs. As James Bonbright concluded in his seminal text
13 *Principles of Public Utility Rates*:

14 ... as setting a general basis of minimum public utility rates and of rate
15 relationships, the more significant marginal or incremental costs are
16 those of a relatively long-run variety – of a variety which treats even
17 capital costs or “capacity costs” as variable costs.¹²

18 Almost three decades later, Alfred Kahn affirmed Bonbright’s opinion
19 in his *The Economics of Regulation*:

¹⁰ National Association of Regulatory Utility Commissioners, *Distributed Energy Resources Rate Design and Compensation*, 118 (November 2016), available at <https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0>.

¹¹ Uncollectible costs are the billed amounts not recovered from customers as a result of those customers’ non-payment of all or a portion of their monthly bills.

¹² James C. Bonbright, *Principles of Public Utility Rates*. Columbia University Press, 348-336 (1961), available at media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.

1 ... the practically achievable benchmark for efficient pricing is more
 2 likely to be a type of average long-run incremental cost, computed for
 3 a large, expected incremental block of sales, instead of [short-run
 4 marginal cost]¹³

5 **Q: Which costs are appropriately recovered through the fixed customer**
 6 **charge?**

7 A: In contrast to the volumetric energy rate, the fixed customer charge should
 8 reflect the cost to connect a customer who uses very little (or even zero)
 9 energy to the distribution grid. Such “customer connection costs” are
 10 limited to the costs of a meter and service drop (including plant and
 11 maintenance) and meter-reading, billing, and other customer-service
 12 expenses.

13 **Q: What is the basis for your opinion regarding which costs are**
 14 **appropriately recovered through the fixed customer charge?**

15 A: My opinion is based on established and enduring rate-design principles. For
 16 example, Bonbright explains that:

17 ... a material part of the operating and capital costs of utility business
 18 is more directly and more closely related to the number of customers
 19 than to energy consumption on the one hand or maximum kilowatt
 20 demand on the other hand. The most obvious examples of these so-
 21 called customer costs are the expenses associated with metering and
 22 billing.¹⁴

23 In their *Public Utility Economics*, Paul Garfield and Wallace Lovejoy
 24 also describe which costs are truly customer-related and therefore
 25 appropriately recovered through the fixed customer charge:

¹³ Alfred E. Kahn, *The Economics of Regulation*, The MIT Press, 85 (1988).

¹⁴ Bonbright, *op. cit.*, 311.

1 The purpose of ... the service charge ... is to cover at least some of the
 2 costs incurred by the utility whether or not the customer uses energy in
 3 a particular month. For small customers under the block meter-rate
 4 schedule, a charge of this kind is intended to cover the expenses
 5 relating to meter service and maintenance, meter reading, accounting
 6 and collecting, return on the investment in meters and the service lines
 7 connecting the customer's premises to the distribution system, and
 8 others. Such expenses as these represent as a minimum the "readiness-
 9 to-serve" expenses incurred by the utility on behalf of each customer.¹⁵

10 More recently, economist Severin Borenstein restated these principles
 11 for designing cost-based fixed customer charges as follows:

12 When having one more customer on the system raises the utility's costs
 13 regardless of how much the customer uses – for instance, for metering,
 14 billing, and maintaining the line from the distribution system to the
 15 house – then a fixed charge to reflect that additional fixed cost the
 16 customer imposes on the system makes perfect economic sense. The
 17 idea that each household has to cover its customer-specific fixed costs
 18 also has obvious appeal on ground of fairness or equity.¹⁶

19 **Q: Is the Company's proposal for the residential BFC consistent with these**
 20 **long-standing principles of cost-based rate design?**

21 A: No. Contrary to these principles, DEC proposes to recover through the
 22 residential BFC not just customer connection costs – i.e., the costs for
 23 meters, service drops, and customer services – but also the costs allocated to
 24 the residential class under the COSS for: (1) Advanced Metering
 25 Infrastructure ("AMI meters"); (2) uncollectible costs; and (3) customer-
 26 related distribution-grid plant.

¹⁵ Paul J. Garfield and Wallace F. Lovejoy, *Public Utility Economics*, Prentice-Hall, Inc., 155-156 (1964).

¹⁶ Severin Borenstein, "What's So Great About Fixed Charges?" (2014), available at <https://energyathaas.wordpress.com/2014/11/03/whats-so-great-about-fixed-charges/>.

1 **Q: Would it be reasonable to recover AMI meter costs through the**
 2 **residential BFC, as DEC proposes?**

3 A: No. Recovering AMI costs through the residential BFC would be
 4 inconsistent with cost-causation principles. The National Association of
 5 Regulatory Utility Commissioners describes cost causation as “an attempt
 6 to determine what, or who, is causing costs to be incurred by the utility.”¹⁷
 7 In this case, the “what” causing DEC to make discretionary investments in
 8 AMI meters is the expectation that such investments would provide benefits
 9 to customers, and the “who” are the customers who would share in these
 10 benefits as a result of the Company’s AMI investments. Thus, in the case of
 11 AMI meters, cost-causation requires that customers contribute toward
 12 recovery of AMI costs in proportion to their share of the AMI benefits.

13 Within the residential class, high-usage, more-sophisticated energy
 14 consumers will likely reap greater benefits than lower-usage customers
 15 from AMI technologies and services.¹⁸ In which case, it would be consistent
 16 with cost-causation principles for larger users to contribute a greater share
 17 toward recovery of AMI costs than smaller users. However, each customer
 18 regardless of usage would contribute the same amount to recovery of AMI
 19 costs if such costs were recovered through the residential BFC. Thus,

¹⁷ National Association of Utility Regulatory Commissioners, *Electric Utility Cost Allocation Manual*, 38 (January 1992).

¹⁸ For a description of the expected customer benefits from the Company’s investment in AMI meters, see *Direct Testimony of Donald Schneider, Jr. for Duke Energy Carolinas, LLC*, Docket No. 2018-319-E (November 8, 2018).

1 recovering AMI costs through the residential BFC, as proposed by DEC,
2 would be contrary to cost-causation principles.¹⁹

3 **Q: Why is the Company's proposal to recover uncollectible costs**
4 **inconsistent with cost-based rate design?**

5 A: Uncollectible costs tend to vary with revenues and thus with usage. Thus, as
6 discussed above, such costs are appropriately recovered through the
7 volumetric energy rate.

8 **Q: How does DEC estimate the customer-related distribution-grid cost per**
9 **residential customer proposed for recovery through the residential**
10 **BFC?**

11 A: As discussed in Section II, DEC relies on the results of its minimum-system
12 analysis to estimate the "customer-related" distribution-grid cost per
13 residential customer. Specifically, as discussed in Section III, the
14 Company's COSS allocates to the residential rate classes in total about \$71
15 million of pole, conductor, conduit, and line-transformer costs that were
16 erroneously classified as customer-related using a minimum-system
17 analysis. Dividing by the number of residential bills yields a "customer-
18 related" distribution-grid cost of \$11.97 per residential customer.²⁰

¹⁹ In addition, the Company's proposal to recover AMI meter costs through the residential BFC would effectively double-count the cost to meter a new customer since the proposed BFC would recover both the cost of AMI meters and the cost of the legacy meters replaced by AMI meters.

²⁰ Calculated based on data provided in the Company's responses to Vote Solar Data Request Nos. 1-20 and 1-28.

1 **Q: Why would it be unreasonable for DEC to recover costs through the**
2 **residential BFC that were classified as “customer-related” using a**
3 **minimum-system analysis?**

4 A: As discussed in Section III, the \$71 million of distribution-grid costs that
5 DEC proposes to recover through the residential BFC are actually demand-
6 related costs that have been misclassified as customer-related in the
7 Company’s minimum-system analysis. Recovering such demand-related
8 costs through the residential BFC would be contrary to long-standing
9 principles of cost-based rate design.

10 Even if the results of the Company’s minimum-system analysis were
11 accepted for *cost-allocation* purposes, such results should not be used for
12 *rate-design* purposes. Minimum-system analyses overstate the minimum
13 cost *per customer* because they assume that a minimum system carrying
14 minimal load would have the same amount of distribution equipment (e.g.,
15 the same number of poles, the same length of conductor) as would a
16 distribution system designed to carry actual distribution load. In other
17 words, the minimum-system method assumes that each piece of distribution
18 equipment would serve the same number of customers on average,
19 regardless of whether the customers are average-sized (as for the actual
20 system) or have minimal demand (as for the hypothetical minimum-size
21 system.)

22 This is not a realistic assumption, since even a minimally sized piece
23 of distribution equipment should be able to serve more minimal-usage
24 customers than the number of average-usage customers served by an
25 average-sized piece of distribution equipment. Consequently, the true
26 distribution-grid cost to serve a customer with minimal usage is likely to be
27 less than that derived using a minimum-system analysis. Indeed, since the

1 minimum-system method attempts to estimate the distribution-grid cost
 2 incurred regardless of usage – i.e., the cost to serve load approaching zero –
 3 the true minimum distribution-grid cost per customer is zero since
 4 distribution equipment that carries zero load can serve an infinite number of
 5 customers with zero load.

6 **Q: Once the excess costs from the minimum-system approach have been**
 7 **removed, what is the resulting cost to connect a residential customer to**
 8 **the distribution grid?**

9 A: As shown in Table 1 below, I estimate that \$12.55 per residential customer
 10 per month would recover the truly customer-related costs of meters, service
 11 drops, and customer services allocated to both the standard-service and
 12 time-of-use rate classes.

13 **Q: How did you derive your estimate of the cost to connect a residential**
 14 **customer to the distribution grid?**

15 A: In response to a data request, DEC provided the unit cost results from a cost
 16 of service study that classifies distribution costs using the Basic Customer
 17 method.²¹ These results show an allocation to the residential rate classes of
 18 about \$94.3 million in customer-related costs. I then adjusted this total in
 19 order to remove AMI and uncollectible costs for the reasons discussed
 20 above. In addition, I reduce this total to correct for an erroneous
 21 classification of overhead line maintenance costs as customer-related.²²

²¹ DEC response to Vote Solar Data Request No. 1-20.

²² The revised COSS based on the Basic Customer method classifies about 32% of the overhead line maintenance expense allocated to the residential classes as customer-related. This is the only cost of service study based on the Basic Customer method that I can recall reviewing during my career that classified *any* overhead line maintenance expense as customer-related.

Dividing the net amount of \$73.9 million by the number of residential bills yields a connection cost per residential customer of \$12.55 per month.

Table 1: Derivation of the Cost to Connect a Residential Customer

	Residential Cost	Residential Bills	Cost per Bill
Customer-Related Cost	\$94,303,956	5,890,613	\$16.01
Less			
AMI Deferral Amortization	\$(10,633,476)	5,890,613	\$(1.81)
Uncollectible Expense	\$(1,939,128)	5,890,613	\$(0.33)
OH Line Maintenance	<u>\$(7,791,038)</u>	5,890,613	<u>\$(1.32)</u>
Total	\$73,940,315		\$12.55

Q: What accounts for the \$15.45 difference between your \$12.55 estimate of the residential connection cost and the \$28.00 residential BFC proposed by DEC?

A: The \$15.45 difference between my \$12.55 estimate of the cost to connect a residential customer and the \$28.00 BFC proposed by DEC represents load-related costs that would be inappropriately recovered through the fixed customer charge under the Company's proposal.²³

Q: Why should the Commission be concerned about the Company's proposal to recover \$15.45 in load-related costs through the BFC?

A: As I discuss in the following sections, this shift in recovery of load-related costs from the volumetric energy rate to the fixed customer charge would give rise to cost subsidization within the residential class and would

²³ Although DEC proposes a BFC of \$27.08 for Schedule RT customers and \$28.00 for all other residential customers, the average rate (weighted by number of customers) across all residential customers is still \$28.00 because there are so few Schedule RT customers.

1 dampen energy price signals to consumers for controlling their bills through
2 conservation, energy efficiency, or distributed renewable generation.

3 **V. DEC's Proposal to Increase the Residential BFC Would Lead to Intra-**
4 **Class Cost Subsidization**

5 **Q: How would the Company's proposal to increase the residential BFC**
6 **cause subsidization within the residential class?**

7 A: As discussed above, DEC's proposal to increase the residential BFC would
8 shift recovery of load-related costs from the volumetric energy rate to the
9 fixed customer charge. Such costs are driven by residential load and are
10 therefore appropriately recovered from each residential customer in
11 proportion to their contribution to class load. To the extent that load-related
12 costs are recovered through the fixed customer charge rather than through
13 the volumetric energy rate, residential customers with below-average usage
14 would bear a disproportionate share of load-related costs and consequently
15 subsidize customers with above-average usage. In other words, a residential
16 customer with below-average usage would pay more, and a residential
17 customer with above average-usage would pay less, than their fair share of
18 such costs.

19 **Q: What is the extent of the intra-class subsidization under the Company's**
20 **proposal for the residential BFC?**

21 A: As explained above, the \$15.45 difference between the \$12.55 residential
22 connection cost and the \$28.00 residential BFC proposed by the Company
23 represents load-related costs that DEC would inappropriately recover from
24 each residential customer every month through a fixed charge on the
25 customer's bill. The Company estimates about 5.9 million residential bills

1 in the test year.²⁴ This means that \$91.0 million of load-related costs would
 2 be recovered annually through the residential BFC under the Company's
 3 proposal.²⁵

4 If the load-related costs recovered through the residential BFC under
 5 the Company's proposal were instead recovered through the volumetric
 6 energy rate, each residential customer would contribute to recovery of these
 7 costs in proportion to their usage. The Company estimates residential sales
 8 in the test year of about 6.2 million megawatt-hours.²⁶ Therefore, if the
 9 \$91.0 million of load-related costs continued to be recovered through the
 10 volumetric energy rate rather than through the residential BFC, they would
 11 be charged at a rate of 1.47 cents per kilowatt-hour ("¢/kWh").²⁷ In this
 12 case, a residential customer with below-average monthly usage of 500 kWh
 13 would contribute about \$88 per year toward recovery of the \$91.0 million
 14 of load-related costs while a customer with above-average monthly usage of
 15 1,500 kWh would contribute about \$264 per year.²⁸ Thus, the 1,500 kWh
 16 customer would contribute three times more than the 500 kWh customer, in

²⁴ The number of residential bills in the test year is provided in the Company's response to Vote Solar Data Request No. 1-28.

²⁵ The \$91.0 million result is derived by taking the product of the annual number of residential bills (5.9 million) and the amount of the proposed residential BFC in excess of residential connection cost (\$15.45 per bill).

²⁶ Residential sales for the test year are provided in the Company's response to Vote Solar Data Request No. 1-28.

²⁷ The 1.47¢/kWh result is derived by dividing \$91.0 million by residential sales of 6.2 million megawatt-hours.

²⁸ Based on data provided in the Company's response to Vote Solar Data Request No. 1-28, I estimate monthly usage of 1,054 kWh for an average residential customer.

1 direct proportion to their usage and consistent with accepted principles of
2 cost-causation.

3 In contrast, under the Company's proposal to recover \$91.0 million of
4 load-related costs through the residential BFC, each residential customer
5 would contribute about \$185 per year toward recovery of such costs
6 regardless of that customer's usage. A below-average 500 kWh customer
7 would therefore pay more than double their fair share of these load-related
8 costs under the Company's proposal while an above-average 1,500 kWh
9 customer would pay only 70% of their fair share.

10 **Q: Would subsidization of high-usage residential customers by low-usage**
11 **customers be eliminated if the residential BFC were set at your**
12 **estimate of the cost to connect a residential customer?**

13 A: No. Even with the residential BFC set at my estimate of residential
14 connection cost, low-usage customers would likely continue to subsidize
15 high-usage customers' costs because customer charges and energy rates are
16 priced at the cost to serve an average-usage customer. For example,
17 Schedule RS customers who reduce their on-peak (and overall) usage with
18 energy efficiency or rooftop solar generation pay the same energy rate as
19 larger, peakier customers even though the latter customers may impose
20 more generation costs per kWh of usage than the former due to their
21 proportionately greater on-peak usage. Likewise, lower-usage customers in
22 an apartment building will typically share a service drop, whereas higher-
23 usage single-family homes will typically be connected with their own
24 service drop. Yet, the lower-usage apartment resident will contribute the
25 same amount toward recovery of service-drop costs as the higher-usage
26 single-family customer even though the cost of a service drop per customer

1 is lower for the former than for the latter customer. In both of these cases,
 2 any differences in the cost to serve smaller and larger customers are
 3 socialized across the residential class, resulting in subsidization of high-
 4 usage customers by low-usage customers.

5 **VI. DEC's Proposal to Increase the Residential BFC Would Dampen**
 6 **Energy Price Signals**

7 **Q: Would the Company's proposal to increase the residential BFC send**
 8 **appropriate price signals?**

9 A: No. As discussed in Section IV, DEC proposes to set the residential BFC at
 10 a rate that greatly exceeds the cost to connect a residential customer to the
 11 distribution grid. The amount in excess of residential connection costs
 12 represents load-related costs that are more appropriately recovered in the
 13 volumetric energy rate. However, under the Company's proposal, this
 14 excess over the cost to connect a residential customer would instead be
 15 inappropriately recovered through the fixed customer charge. This shift in
 16 the recovery of load-related costs from the volumetric energy rate to the
 17 fixed customer charge would dampen price signals and discourage
 18 economically efficient behavior by residential customers.

19 **Q: To what extent would the Company's proposal to increase the**
 20 **residential BFC dampen price signals provided by the residential**
 21 **volumetric energy rate?**

22 A: With a fixed amount of revenue requirements to be recovered from the
 23 residential class, the higher the residential BFC, the lower the volumetric
 24 energy rate, and vice versa. As shown below in Table 2, with the BFC set at
 25 \$28.00, DEC proposes an average energy rate of 10.02¢/kWh in order to

1 recover the requested allocation of total revenue requirements to Schedule
 2 RS customers.²⁹ If, instead, the BFC were set at my \$12.55 estimate of the
 3 cost to connect a residential customer, I estimate that the average energy
 4 rate for Schedule RS customers would have to be increased to 11.56¢/kWh
 5 to recover the same allocated revenue requirement.³⁰

6 **Table 2: Schedule RS Energy Rates with Connection-Cost and DEC's**
 7 **Proposed BFC (¢/kWh)**

	Rate With Connection- Cost BFC	Rate With DEC's Proposed BFC	Rate Difference	% Difference
First 1000 kWh	11.36	9.85	(1.51)	-13.3%
Over 1000 kWh	<u>12.11</u>	<u>10.50</u>	<u>(1.61)</u>	-13.3%
Average	11.56	10.02	(1.53)	-13.3%

8 For the average Schedule RS customer with a monthly usage of 1,007
 9 kWh, the price signal would be provided by the volumetric rate for the
 10 second energy block (applicable to monthly usage in excess of 1,000
 11 kWh).³¹ As shown in Table 2, DEC proposes a rate for the second energy
 12 block of 10.50¢/kWh. With the BFC set at \$12.55, I estimate an energy rate
 13 for the second block of 12.11¢/kWh. In other words, DEC is proposing a
 14 rate for the second energy block that is 1.61¢/kWh, or about 13%, less than
 15 what the rate would be if the Schedule RS BFC were set at the cost to
 16 connect a residential customer. Thus, the Company's proposal for the

²⁹ Provided in the Company's response to Vote Solar Data Request No. 1-28.

³⁰ For the purposes of this calculation, I assume the same inclining-block rate structure for the block volumetric energy rates as proposed by DEC.

³¹ My estimate of the monthly usage of an average Schedule RS customer is derived from data provided in the Company's response to Vote Solar Data Request No. 1-28.

1 Schedule RS BFC would dampen the price signal provided by the
2 volumetric energy rate by about 13%.

3 **Q: How would residential customers likely respond to the reduction in the**
4 **energy price signal resulting from the Company's proposal for the**
5 **residential BFC?**

6 A: Since the volumetric energy rate under the Company's proposal for the
7 residential BFC would be lower than the volumetric energy rate with a
8 residential BFC of \$12.55, I would expect residential customers to consume
9 more energy with the Company's proposed BFC than they would with a
10 BFC set at the cost to connect a residential customer. The magnitude of the
11 increase in energy consumption would depend on: (1) the extent to which
12 the volumetric energy rate with the Company's proposed residential BFC is
13 lower than the volumetric energy rate with the BFC set at residential
14 connection cost; and (2) the price elasticity of electricity demand.

15 **Q: What is the price elasticity of electricity demand?**

16 A: Residential customers respond to the price incentives created by the
17 electrical rate structure. Those responses are typically measured as price
18 elasticities, i.e., the ratio of the percentage change in consumption to the
19 percentage change in price. Price elasticities are generally low in the short
20 term and rise over several years, because customers have more options for
21 increasing or reducing energy usage in the medium to long term. For
22 example, a 2004 review of 36 articles on residential electricity demand
23 published between 1971 and 2000 reported that, on average across these

studies, consumption decreased by 0.35% in the short term and by 0.85% in the long term for every 1% increase in price.³²

Studies of electric price response typically examine the change in usage as a function of changes in the marginal rate paid by the customer.³³ Table 3 below lists the results of seven studies of marginal-price elasticity over the last forty years.³⁴

Table 3: Summary of Marginal-Price Elasticities

Authors	Date	Elasticity Estimates
Acton, Bridger, and Mowill	1976	−0.35 to −0.7
McFadden, Puig, and Kirshner	1977	−0.25 without electric space heat and −0.52 with space heat
Barnes, Gillingham, and Hageman	1981	−0.55
Henson	1984	−0.27 to −0.30
Reiss and White	2005	−0.39
Xcel Energy Colorado	2012	−0.3 (at years 2 and 3)
Orans et al, on BC Hydro inclining-block rate	2014	−0.13 in 3 rd year of phased-in rate

Q: What would be a reasonable estimate of the marginal-price elasticity for changes in the residential volumetric energy rate?

A: From Table 3, it appears that a marginal-price elasticity of −0.3 – that is, a 0.3% decrease in consumption for every 1% increase in price – would be a reasonable mid-range estimate of the impact over a few years.

³² Espey and Espey (2004). Specifically, the review reported short-run elasticity estimates of about −0.35 on average across studies and long-run elasticity estimates of about −0.85 on average across studies. The full citation for this study is provided in Exhibit JFW-2.

³³ For the average Schedule RS customer with a monthly usage of 1,007 kWh, that would be the rate for the second energy block (applicable to monthly usage in excess of 1,000 kWh).

³⁴ The citations for these studies are provided in Exhibit JFW-2.

1 **Q: What would be a reasonable estimate of the effect on energy use from**
2 **the Company's proposal for the Schedule RS BFC?**

3 A: As discussed above, if the Schedule RS BFC were increased as proposed by
4 DEC, the rate for the second energy block would be about 13% less than
5 what the volumetric rate would be if the BFC were set at residential
6 connection cost. Assuming an elasticity of -0.3 , this 13% reduction in the
7 volumetric energy rate would result in an increase in energy consumption of
8 about 4% for the average Schedule RS customer. This means that all else
9 being equal, Schedule RS load after a few years with the \$28.00 BFC
10 proposed by DEC would be expected to be about 4% higher than it would
11 have been if the BFC had been set at the cost to connect a residential
12 customer.

13 **VII. Conclusions and Recommendations**

14 **Q: What do you conclude with respect to the Company's use of the**
15 **minimum-system method to classify distribution-grid costs in its**
16 **COSS?**

17 A: The Commission should reject the Company's reliance on a minimum-
18 system analysis to classify distribution-grid costs in the COSS. This
19 inherently flawed analysis erroneously classifies some distribution-grid
20 costs – a portion of the cost of poles, wires, conduits, and transformers – as
21 customer-related, even though they are in fact driven by usage and therefore
22 properly classified as demand-related. The Company's COSS thereby
23 overstates the amount of customer-related costs appropriately recovered
24 through the residential BFC.

1 Instead, as has been the practice for the past three decades, DEC
2 should classify all such distribution-grid costs as demand-related. Only the
3 costs incurred by DEC to connect customers to the distribution grid – i.e.,
4 the cost of meters, service drops, and meter-reading, billing, and other
5 customer-service expenses – should be classified as customer-related.

6 **Q: What do you conclude with respect to the Company's proposal to**
7 **increase the residential BFC?**

8 A: The Company's proposal would inappropriately shift load-related costs
9 from the volumetric energy rate to the fixed customer charge, dampen price
10 signals to consumers for reducing energy usage, disproportionately and
11 inequitably increase bills for the Company's smallest residential customers,
12 and result in subsidization of larger residential customers' costs by
13 customers with below-average usage. Accordingly, the Commission should
14 reject the Company's proposal to increase the BFC for residential
15 customers.

16 **Q: Should the residential BFC be set at your estimate of the cost to connect**
17 **a residential customer to the distribution grid?**

18 A: No. In direct testimony also filed in this proceeding on behalf of SC
19 NAACP, CCL, and Upstate Forever, John Howat finds that low-income
20 customers would be disproportionately harmed by an increase in the
21 residential BFC. In order to mitigate this harm, I recommend that the BFC
22 for the residential rate classes be increased from current levels by the same
23 percentage as the revenue increase (if any) ultimately authorized by the
24 Commission in this proceeding for those classes. With my recommended
25 approach, the percentage impact on customer bills from the authorized
26 revenue increase would be essentially uniform across all usage levels.

1 By way of example, if the Commission were to approve the
2 Company's request for a 12.3% increase in Schedule RS revenues, the
3 Schedule RS BFC would be increased by 12.3% under my recommended
4 approach. In this example, a Schedule RS customer's bill would increase by
5 essentially the same percentage regardless of whether that customer's usage
6 was below-average, average, or above-average.

7 **Q: Does this conclude your direct testimony?**

8 A: Yes.

STATE OF SOUTH CAROLINA
BEFORE THE PUBLIC SERVICE COMMISSION
DOCKET NO. 2018-319-E

I certify that the following persons have been served with one (1) copy of Direct Testimony of Jonathan Wallach by electronic mail and/or U.S. First Class Mail at the addresses set forth below:

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This the 26th day of February, 2019.

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SUMMARY OF PROFESSIONAL EXPERIENCE

- 1990–Present* **Vice President, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, regulation, and restructuring. Designs and assesses resource-planning strategies for regulated and competitive markets, including estimation of market prices and utility-plant stranded investment; negotiates restructuring strategies and implementation plans; assists in procurement of retail power supply.
- 1989–90* **Senior Analyst, Komanoff Energy Associates.** Conducted comprehensive cost-benefit assessments of electric-utility power-supply and demand-side conservation resources, economic and financial analyses of independent power facilities, and analyses of utility-system excess capacity and reliability. Provided expert testimony on statistical analysis of U.S. nuclear plant operating costs and performance. Co-wrote *The Power Analyst*, software developed under contract to the New York Energy Research and Development Authority for screening the economic and financial performance of non-utility power projects.
- 1987–88* **Independent Consultant.** Provided consulting services for Komanoff Energy Associates (New York, New York), Schlissel Engineering Associates (Belmont, Massachusetts), and Energy Systems Research Group (Boston, Massachusetts).
- 1981–86* **Research Associate, Energy Systems Research Group.** Performed analyses of electric utility power supply planning scenarios. Involved in analysis and design of electric and water utility conservation programs. Developed statistical analysis of U.S. nuclear plant operating costs and performance.

EDUCATION

BA, Political Science with honors and Phi Beta Kappa, University of California, Berkeley, 1980.

Massachusetts Institute of Technology, Cambridge, Massachusetts. Physics and Political Science, 1976–1979.

PUBLICATIONS

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